STATEMENT OF BASIS

NATURAL SODA, INC
CLASS III SOLUTION MINING
RIO BLANCO COUNTY, CO

EPA AREA PERMIT NO. CO32169-00000

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This STATEMENT OF BASIS gives the derivation of site-specific UIC Permit conditions and reasons for them. Referenced sections and conditions correspond to sections and conditions in the Permit.

EPA UIC permits regulate the injection of fluids into underground injection wells so that the injection does not endanger underground sources of drinking water. EPA UIC permit conditions are based upon the authorities set forth in regulatory provisions at 40 CFR Parts 144 and 146, and address potential impacts to underground sources of drinking water. Under 40 CFR §144.35, issuance of this permit does not convey any property rights of any sort or any exclusive privilege, nor authorize injury to persons or property of invasion of other private rights, or any infringement of other Federal, State or local laws or regulations. Under 40 CFR §144 Subpart D, certain conditions apply to all UIC Permits and may be incorporated either expressly or by reference. General Permit conditions for which the content is mandatory and not subject to site-specific differences (40 CFR Parts 144, 146 and 147) are not discussed in this document.

Upon the Effective Date when issued, the Permit authorizes the construction and operation of injection wells so that the injection does not endanger underground sources of drinking water, governed by the conditions specified in the Permit. The Permit is issued for the operating life of the injection well or project unless terminated for reasonable cause under 40 CFR §144.39, §144.40 and §144.41. The permit is subject to EPA review at least once every five (5) years to determine if action is required under 40 CFR §144.36(a).

PART I. General Information and Description of Facility

Natural Soda, Inc.
3200 Rio Blanco County Road 31
Rifle, CO 81650

on

March 18, 2010

submitted an application for an Underground Injection Control (UIC) Program area permit to construct and operate Class III injection well or wells within the permitted area which is described by the Permittee's Bureau of Land Management's lease boundary:

Lease No. C-0118327: Township 1S, Range 98W, Sections 23, 24, 25, 26

Lease No. C-0118326: Township 1S, Range 98W, Sections 13, 14, 15 (NE1/4, SE1/4NW1/4, S1/2), 21 (NE1/4NE1/4, S1/2NE1/4, NE1/4SW1/4, SE1/4), 22 (W1/2SW1/4, SE1/4SW1/4)

Lease No. C-37474: Township 1S, Range 98W, Sections 16 (N1/2NE1/4, SW1/4NE1/4, W1/2, NW1/4SE1/4), 17, 20 (NE1/4NE1/4), 21 (NW1/4NW1/4)

Lease No. C-0119986: Township 1S, Range 98W, Sections 21 (S1/2SW1/4), 27, 28, 29 (SE1/4NE1/4, S1/2SW1/4, S1/2SE1/4, NE1/4SE1/4), 33, 34 (NW1/4)

The following injection well is included in this area permit:

Deep Vertical Production Well (DVPW)
591 FSL, 1896 FEL, SWSE S26, T1S, R98W
Rio Blanco County, CO

The application, including the required information and data necessary to issue or modify a UIC Permit in accordance with 40 CFR Parts 144, 146 and 147, was reviewed and determined by EPA to be complete. Regulations specific to Colorado injection wells are found at 40 CFR §147 Subpart G.

The Permit will expire upon delegation of primary enforcement responsibility (primacy) for applicable portions of the UIC Program to the State of Colorado unless the delegated agency has the authority and chooses to adopt and enforce this Permit as a State Permit.

PROJECT DESCRIPTION

Natural Soda, Inc. (NSI) has submitted an application for a Class III Solution Mining area permit to mine the Saline Zone in the Parachute Creek Member of the Green River Formation which includes one injection well. The proposed well is within their existing Bureau of Land Management (BLM) sodium leases where solution mining activities have been authorized under their UIC Class III Permit CO30358-00000, within the bedded nahcolite in the L-5 stratigraphic zone of the Green River Formation. The singly proposed injection well is sited on an existing pad of their present operations and will be utilizing the existing infrastructure and will operate under similar maximum pressures and temperatures. The proposed permit differs from the authorized CO30358-00000 in well construction and the injection zone. The injection zone is deeper than their existing permit allows.

Adjacent to the NSI lease site, another BLM lease has been issued to American Soda, which is presently permitted under UIC Class III Permit CO30358-00000. At this time, the wells associated with the America Soda permit are shut-in and the facility is not operational. Similar to the American Soda operation, this NSI permit intends to also solution mine the nahcolite resources in the Saline Zone, but at lower operating temperatures and pressures. The Saline Zone consists of thin beds separated by disseminated nahcolite crystals, aggregates, and nodular nahcolite. NSI intends to recover nahcolite or more commonly known as sodium bicarbonate ($NaHCO_3$), a product used in the manufacturing of food, pharmaceuticals, fire extinguishers, laboratory reagents, cattle feed supplement, and other products.

The Dissolution Surface represents the lowermost penetration of circulating groundwater into the Parachute Creek Member, below which are the formations that comprise the Saline Zone, which is described to be completely dry. NSI has proposed to inject into the Saline Zone that includes the L-4, R-4, L-3, R-3, L-2, and R-2 stratigraphic zones. At the location of the DVPW, the depth of the top of the Saline Zone is approximately 1,904 feet.

In the proposed well design, the injection and production activities coexist in one well through two strings. Either string may be used for injection or production. See APPENDIX A of the permit for the well diagram. The injection and production tubings will be packerless, to allow for greater adjustability and ease to control the production horizon. Initially, the heated water, or barren liquor from NSI's existing operation, will be injected into the mining interval to dissolve the soluble nahcolite. The pressure differential between the subsurface and the wellhead, established by a pump, will push the saturated brine to the surface, where it will be processed at their existing sodium bicarbonate plant. If unsuccessful, a pump may be installed to bring the pregnant solution to surface. What remains, after cooling the high temperature pregnant solution to crystallize the pure sodium bicarbonate, is barren liquor. The barren liquor is heated and recycled back into the well to repeat the process.

NSI initially proposes to drill one well, the DVPW, to determine the commercial viability of mining thinly bedded and disseminated nahcolite within the Saline Zone through a vertical well. This well will be used to determine optimal operational parameters necessary for commercial production, better understand the growth rate and growth characteristics of mined interval, determine composition of production fluids for processing optimization, and gather geophysical data of the mining zone.

Unlike the nahcolite that was deposited as thick Boies bed in the shallower formations that is the target of the existing Class III Permit CO30358-00000, in the Saline Zone, the deposit is better described as disseminated nahcolite embedded within the oil shale, with several thin beds, the Love Bed, Greeno Bed, and TI bed. The nodules and individual crystals in the disseminated nahcolite make up approximately 25% to 30% of the rock volume and as the nodules and crystals dissolve leaving the shale oil structure in place. Even in the thin beds, approximately 30% of the shale oil structure remains in place after the nahcolite has been removed.

NSI expects to produce a cylindrical shape that is approximately 500 feet high and an approximate diameter of 250 feet. The maximum operating temperature will be 300 degrees Fahrenheit (deg F) and will be controlled at the surface. The maximum fluid injection pressure at the surface is 300 psig and the flowrates is anticipated to be up to 400 gpm.

Initially, as part of this area permit, NSI proposes to permit only one well, the DPVW, but if it is proven to be successful, NSI intends to add additional wells to the area permit.

PART II. Permit Considerations (40 CFR §146.34)

Hydrogeologic Setting

The primary water-bearing zones that exist in this area are within the Uinta and Green River Formations. Four principal water-bearing hydrostratigraphic units are locally recognized. These are known as the Perched Aquifer, A-Groove Aquifer, B-Groove Aquifer, and the Dissolution Surface Aquifer. It is assumed that TDS concentrations increase gradually with depth between the B-Groove aquifer and the Dissolution Surface. The A-Groove and the B-Groove aquifers are in hydrologic communication through the leaky semi-confining oil shale-rich layer called the Mahogany (R-7 zone) aquitard. Historically, the B-Groove and the Dissolution Surface aquifer were once thought to be separated by a leaky semi-confining oil shale-rich layer called the R-6 zone, however data generated from investigative studies prior to the mining activities associated with CO30358-00000 has shown that the R-6 serves as a confining layer and the B-Groove is not in hydrologic communication with the Dissolution Surface. The perched aquifer appears to remain hydraulically isolated at this site.

Regionally, recharge to the aquifer system occurs principally from snowmelt during the spring. In the recharge areas, water from the A-Groove Aquifer moves downward through the Mahogany Zone to recharge the B-Groove Aquifer. A minor amount of water moves downward through the R-6 zone to recharge the Dissolution Surface Aquifer. Generally groundwater in the A-Groove and B-Groove Aquifers flow from the recharge areas at the basin margins toward the north-central part of the basin.

In discharge areas, water moves upward from the B-Groove and Dissolution Surface Aquifers through the R-6 and Mahogany Zones to the A-Groove Aquifer. Water is discharged from the A-Groove Aquifer to the alluvium through valley floors and by springs along the valley walls. Groundwater flows through the alluvium to the streams and is lost from the basin by evapotranspiration and discharge to Piceance Creek and Yellow Creek.

Geologic Setting

The Piceance Creek Basin located in western Colorado is an elongated structural depression, trending northwest - southeast. The basin is bounded by the Uinta Uplift to the north, the White River Uplift to the east, the Sawatch Uplift to the southeast, and the Douglas Creek Arch to the west, encompassing an area of approximately 890 square miles. The basin is asymmetric, and it is structurally deepest in the northwest where crystalline basement rocks are estimated to be 24,000 feet below ground surface. The basin contains reserves of coal, natural gas, oil shale, and is also mined for the sodium mineral nahcolite. Sodium chloride and dawsonite are potential mineral resources, but are not currently mined.

In this area, the Piceance Creek Basin is dominated by surficial outcrops of the Uinta Formation which overlies the Green River Formation, both of Eocene age. The Uinta Formation is characterized by low porosity sandstone and siltstone with intertongues of Green River Formation marlstone and oil shale, approximately 1,200 feet thick. The underlying Green River Formation is locally divided into three members; the Parachute Creek Member, the Garden Gulch Member, and Douglas Creek Member.

The Parachute Creek Member is the thickest (approximately 1,700 feet thick) and to date, the most economically important unit in the Green River Formation. The Parachute Creek Member has a large areal extent and contains all of the commercial resources of oil shale, nahcolite, dawsonite, and halite. Oil shale, or kerogenitic marlstone, is the dominate lithology of the Parachute Creek Member; but it also contains marlstones, nahcolite, dawsonite, and halite. Below the Parachute Creek Member is the Garden Gulch Member, where the oil shale is characterized as clay rich, roughly approximated by a 60% clay and 40% carbonate, in contrast to the carbonate rich Parachute Creek oil shale, which is roughly approximated as 60% carbonate and 40% clay.

The oil shale intervals within the Parachute Creek and Garden Gulch Members are further subdivided into seventeen, alternating rich (R) and lean (L) oil shale zones. NSI has targeted the L-4 through L-2 stratigraphic zones in the Parachute Creek for solution mining.

Uinta

Within the confines of the lease boundary, the thickness ranges from 717 to 1,255 feet, and averages 1,110 feet. Four major intervals of sandstone and siltstone are interstratified with three horizons of silty marlstone, marlstone and lean oil shale.

Sandstone tends to be fine to medium-grained, with thin beds (1 to 2 feet) of coarse-grained sandstone and pebbly sandstone. Siltstone, sandy siltstone and marly siltstone are often interstratified with sandstone. Above the water table, rocks are typically brown, tan or buff colored, while below the water table, they are usually gray. Marlstone and silty marlstone horizons are usually tan to brown in color and usually well stratified; laminations and discontinuous laminations are common. Lean oil shale beds are often associated with marlstone. These rocks are usually dark brown to brown and well laminated.

Parachute Creek Member of Green River Formation

The Parachute Creek Member can be divided locally into two major units, the Saline Zone and an overlying Leached Zone, by the Dissolution Surface. The Dissolution Surface also marks the interface above which water has dissolved the soluble salts, and below which the soluble salts remain. The Leached Zone is the result of dissolution of soluble saline minerals by downward percolation of ground water. The Saline Zone is a complex array of bedded halite deposits and bedded and non-bedded nahcolite.

<u>Leached Zone</u>
The Leached Zone has been defined as the interval from the Dissolution Surface to the uppermost dissolution feature. Rock types vary from marlstone and oil shale rubble to massive oil shale, claystone and marlstone. Stratigraphically, it contains the R-8 zone downward to include part to all of the L-5 zone. The amount of L-5 zone included depends on the stratigraphic position of the Dissolution Surface. Where the Dissolution Surface is relatively high, as it is throughout most of the Lease, only the upper 100 to 200 feet of the L-5 zone is included in the Leached Zone. The remainder (50 to 160 feet) is included in the Saline Zone. Where the Dissolution Surface has penetrated further downward into the Parachute Creek Member, all of the L-5 zone and the upper part of the R-5 zone are included in the Leached Zone. This situation occurs only around the margins of the Lease, especially west of Yellow Creek in the Lease "annex".

The basal 50 to 100 feet of the Leached Zone is intensely leached and rubblized, but does not produce large amounts of groundwater. Discharge is generally greater in the upper 50 feet of the R-6 zone and in the B-Groove. In fact, discharge from the vuggy oil shales in the lower interval of the Mahogany Zone is often greater than anywhere in the Leached Zone. Overall in the Lease area, the Leached Zone has a thickness ranging from 650 to 700 feet.

R-8 Zone

The R-8 oil shale zone, ranges in thickness from 160 to 194 feet within the lease, and averages 175 feet. It is composed of interbedded oil shales and occasional interbeds of siltstone, marlstone and volcanic tuff. Oil shale and marlstone are typically laminated and tan to dark brown in color.

Nahcolite was once present in the R-8 zone in the Lease area, but has been subsequently removed by groundwater. The presence of former saline minerals is marked by small vugs and cavities which average less than 0.5 foot in diameter. Usually the first vugs are located near the base of the upper one-third of the R-8.

A-Groove

Within the lease, the A-Groove is 14 to 20 feet thick, averaging 16 feet. It is composed of tan to yellowish-tan lean oil shale and silty marlstone, and has a distinct “weathered" appearance. In core hole samples on the Lease, the A-Groove usually contains two or more dissolution rubble zones, each generally less than 10 feet thick.

Mahogany Zone

The Mahogany Zone ranges in thickness from 170 to 181 feet and averages 175 feet, within the lease. Usually the Mahogany is subdivided into an upper, middle and lower interval. The upper interval is usually about 30 feet thick and composed of oil shale that is generally laminated and dark gray to brown in color. The Mahogany Marker, a distinctive, thin (about 0.4 feet) tuff, is present at the base of the upper interval. The middle interval contains the richest oil shales in the Mahogany Zone and is approximately 60 feet thick. Middle interval oil shale is usually laminated or structureless; however, blebby oil shale is present, especially in several of the richest beds. The Mahogany Bed which occurs near the top of the middle interval, and is the most kerogen-rich horizon in the entire Mahogany Zone, however, has laminated stratification. The lower interval of the Mahogany Zone is approximately 65 feet thick, tan to grayish-brown to dark brown in color and usually laminated or structureless. The lower interval contains numerous horizons of vugs and dissolution rubble and is similar in appearance to the Leached Zone which lies below.

B-Groove

Like the A-Groove above, the B-Groove is composed of marlstone, silty marlstone and lean to low-grade oil shale. Most of the B-Groove has a weathered or leached appearance and the upper one-half often contains a thick (5 to 10 feet) rubble horizon. Average thickness of the B-Groove is 20 feet in the Lease area.

R-6 Zone

The R-6 zone has an average thickness of 176 feet in the Lease area. The unit is composed primarily of oil shale, vuggy oil shale, oil shale breccia (dissolution) and marlstone. Rocks in the upper 30 to 40 feet and in the lower 80 to 90 feet of the R-6 are usually laminated or diffusely laminated, while the middle 50 to 60 feet have blebby or streaked stratification. In the upper part of the R-6, a 10 to 20-foot thick bed of claystone and clay-rich oil shale is present throughout the Lease area. Dissolution features are abundant in the R-6 zone and range from minute millimeter-sized pits to blocky rubble horizons five to 10 feet thick. Oil shale beds containing dissolution features are interstratified with more massive oil shale beds free of such items. As stated in the Hydrogeological Setting section, regionally, the historical groundwater model has described the R-6 zone as a leaky semi-confining oil shale-rich layer. However, based on the following body of information: 1) During a period of pressurized injection during the pilot phase of operation the static water level of the Dissolution surface was raised well above the level of the static water levels of the two upper aquifers and no impacts to the A-Groove and B-Groove Aquifers were detected. Water levels have since been returned to their more historic levels. 2) During the initial site feasibility study water production data was collected from well 88-1 during drilling. Data show that the proposed confining zone (R-6) produced little or no water. And, 3) there are no observed water quality changes to the water in the B-Groove and A-Groove aquifer monitoring wells, the R-6 Zone beneath the existing NSI mining area acts as a confining interval.

L-5 Zone (Leached Zone)

The L-5 zone is similar lithologically to the overlying R-6 zone, however, it has a lower average oil shale content and a higher density of dissolution features. Throughout the Lease, the total L-5 zone (leached and saline parts) has an average thickness of about 197 feet. As discussed in a previous section, one-half to two-thirds of the L-5 zone is usually included in the Leached Zone. Most of the leached L-5 zone is composed of vuggy and/or rubblized oil shale or marlstone. Stratification in these rocks is generally laminated, sometimes structureless. Near the base of the L-5 zone, just above the Dissolution Surface, are a series of dissolution rubble zones ranging in thickness from less than one foot to more than 25 feet.

Saline Zone

The Saline Zone constitutes the most important resource interval in the entire Piceance Creek Basin. It not only contains tremendous quantities of oil shale but equally large concentrations of nahcolite, dawsonite, and halite. Recent resource assessments by the U.S. Geological Survey indicate that the Saline Zone under most of the Lease represents an in-place oil shale resource of about 1.9 million barrels per acre and nahcolite resources for the Lease are on the order of 4.5 billion tons, or 542,541 tons per acre. The U.S. Department of Interior indicated that dawsonite resources for the Lease are also high, approximately 195,000 tons per acre.

The Saline Zone is bounded at the top by the Dissolution Surface, and at the base by a horizon that marks the lowermost occurrence of nahcolite in the R-2 zone. Besides parts of the L-5 and R-2 zones, the Saline Zone also includes all of the R-5, L-4, R-4, L-3, R-3 and L-2 zones.

Core drilling on the Lease indicates that the Saline Zone ranges in thickness from 926 to 1,112 feet and averages 1,018 feet. It is thickest (in excess of 1,150 feet) in the northern part of the Lease and thinnest (400 to 800 feet) along the western boundary. The overall appearance of the Saline Zone is one of a broad circular dome with "steep" flanks and a "fairly flat" crest.

L-5 Zone (Saline Zone)

The saline part of the L-5 zone is usually located in the lowermost one-third to one-half of the L-5 zone. This saline section of the L-5 zone constitutes the upper Saline Zone and is comprised primarily of kerogen-rich nahcolitic oil shale and thick (30 to 70 feet), massive beds of stratiform nahcolite, halite or mixed nahcolite and halite. Overall, the L-5 zone has highly variable quantities of nahcolite, dawsonite and oil shale because of the effects of nahcolite to halite transitions in the Boies Bed, L-5D and L-5E horizons.

Collectively, the entire saline section of the L-5 zone is often referred to as the Upper Salt. Four major horizons of intense nahcolite or halite mineralization may be present in the L-5 zone: Boies Bed (L-5A), L-5B, L-5D and L-5E. The Boies Bed generally consists of a 30 to 32-foot thick bed of white granular nahcolite in the southern part of the Lease, but grades laterally into a 70-foot thick nahcolitic halite bed to the north. The existing UIC Class III CO30358-00000 permit mines from this zone.

The nahcolitic oil shale horizons between the massive nahcolite and halite beds often exhibit a plastic or "rubbery" characteristic. These rubber zones are important for the protection of halite and nahcolite in the upper Saline Zone from groundwater in the overlying Leached Zone. Additionally, they make effective seals during solution mining of the Boies Bed.

R-5 Zone

The R-5 zone is one of the thickest intervals in the Saline Zone and in the entire Parachute Creek Member. In the Lease area it is the thickest stratigraphic unit, ranging in thickness from 358 to 402 feet, and averaging 376 feet. Variations in thickness in the R-5 in the Lease area are due primarily to the stratigraphic characteristics of the Lower Salt, an 80 to 100-foot thick interbedded sequence of stratiform nahcolite and halite, and nahcolitic oil shale at the base of the zone. Like the overlying L-5 zone, the R-5 zone has variable resource characteristics, primarily because of mineralogic changes in the Lower Salt.

L-4 Zone

The L-4 zone, unlike the overlying R-5 and L-5 zones, does not contain horizons of stratiform halite. It is composed primarily of nahcolitic oil shale and ranges in thickness from 136 to 162 feet, averaging 152 feet. Within the L-4 are a number of thin beds, among them the Love Bed.
Oil shale interbedded with the thin beds is characteristically nahcolitic. Nonstratiform nahcolite (crystals and crystal aggregates) appears to be most abundant in laminated or structureless oil shale; blebby and streaked oil shales usually have minor amounts.

R-4 Zone

The R-4 zone, in contrast to the L-4 zone, has a much lower content of nahcolite. Rather, it is characterized by rich to very rich oil shale. Most of the oil shale in the R-4 zone is free of nahcolite or has only a few scattered aggregate bodies. The lower 40 to 50 feet usually lacks nahcolite entirely. These rocks are very rich in kerogen, and have well developed blebby and/or streaked stratification.

L-3 Zone

The L-3 is the thinnest oil shale horizon in the Saline Zone, averaging 27 feet. Lithologically, the L-3 zone is dominated by oil shale and has very well developed laminated stratification. Repetition of sets of thin laminae often gives the rock a "banded" appearance. The L-3 zone does not have any correlatable nahcolite horizons.

Fracturing in the L-3 zone is much greater than in the R-4 zone above and R-3 zone below. These fractures are generally closely spaced, less than one foot long, and nearly vertical. They often have a thin (1 to 2 mm) coating of asphalt-like organic matter (bitumen). It is possible that the fractures provide a certain amount of secondary permeability for the movement of methane.

R-3 Zone

The R-3 zone has one of the highest nahcolite contents in the entire Saline Zone and averages 152 feet in thickness. Nahcolite in the R-3 zone consists almost entirely of aggregate bodies and disseminated crystals. Several thin (less than one foot), contorted, microcrystalline nahcolite horizons are present in the upper part of the zone. Because of the high nahcolite content, oil shale stratification in the R-3 zone is often difficult to discern. Where present, streaked, blebby and indistinctly laminated types have been observed.

Five mappable horizons of oil shale with high concentrations of nahcolite aggregates and crystals are present in the R-3 zone: R-3B, R-3D (Greeno Bed), R-3F, R-3H, and R-3J. The R-3J bed, which immediately underlies the L-3 zone, is composed of roughly equal amounts of nahcolite aggregates and crystals. Aggregate bodies are moderately to coarsely crystalline and have a spherical or rounded irregular shape. Concentration of individual nahcolite crystals ranges from less than 10 to more than 70 % by volume; honeycomb and semi-honeycomb types are most common. These high concentrations of crystals occur mainly in oil shale beds (one to two feet thick) in the lower one-half of the R-3J. Overall, the R-3J bed has an average nahcolite content of about 44.3 weight percent and an average thickness of about 20.8 feet.

It should be noted that oil shale intervals located between the mappable horizons of nahcolite also contain nahcolite. This nahcolite consists of both aggregates and crystals. The thickest intervals of nahcolite-free oil shale occur below the Greeno Bed, it averages about eight feet in thickness. These typically have streaked and/or blebby stratification and high oil shale contents.

L-2 Zone

The L-2 zone is a thin horizon, averaging about 35 feet, and has many characteristics similar to the L-3 zone. The upper 20 to 25 feet of the L-2 zone is composed of laminated (banded) lean to moderate-grade dawsonitic oil shale. Like the L-3 zone, this interval has numerous fractures with common infillings of organic material. The lower eight to 10 feet of the L-2, however, is considerably different, consisting of dark brown honeycomb nahcolite the L-2A (TI) bed. In total, the L-2 zone averages about 27.7 weight percent nahcolite, 8.6 weight percent dawsonite and 14.3 gallons per ton oil shale. If the TI bed is excluded, the L-2 zone has oil shale, nahcolite, and dawsonite contents very similar to the L-3 zone.

The TI bed is the lowest mappable horizon of nahcolite in the Saline Zone and the only mappable horizon in the L-2 zone. It is usually 6.5 to 7.0 feet thick in core holes. In core hole MMC-IRI-1 the average nahcolite content is about 73 weight percent; oil shale averages about 11 gallons per ton. As mentioned previously, the TI bed is very similar in composition and appearance to the Greeno Bed. It does, however, usually have slightly less nahcolite than the Greeno.

R-2 Zone

The R-2 zone represents the lowest oil shale unit in the Parachute Creek Member. In the Lease area it averages about 94 feet in thickness. Only the upper 30 to 40 feet of the R-2 zone contains nahcolite and is thus included in the Saline Zone.

The nahcolite-bearing part of the R-2 zone is composed of laminated, streaked or blebby oil shale. Laminated oil shale usually contains some nahcolite aggregates or crystals, while the streaked and/or blebby shale is nahcolite free. Overall, the saline interval of the R-2 zone contains about 15 weight percent nahcolite, 4 weight percent dawsonite, and high concentrates of oil shale. The nahcolite that does occur is not sufficiently concentrated in definitive mappable nahcolitic oil shale horizons such as occur higher in the Saline Zone.

The lower, nahcolite-free part of the R-2 zone consists mostly of laminated and diffusely laminated oil shale; streaked and/or blebby oil shale is also common but subordinate in abundance. Laminated oil shales, especially those near the base of the R-2 zone, have much higher clay contents than normal. Lithologically, they resemble oil shale in the underlying Garden Gulch Member.

Garden Gulch Member of Green River Formation

The Garden Gulch Member underlies the Parachute Creek Member and is 300 to 350 feet thick in the Lease area. Like the overlying Parachute Creek Member, the Garden Gulch Member can be subdivided into rich and lean oil shale zones. The uppermost zone is designated the L-1 zone, and the contact between the L-1 and the overlying R-2 is called the “Blue Marker”. The L-1 zone is composed of clay-rich lean oil shale and claystone and is about 25 to 30 feet thick. The L-1 zone is underlain by the R-1 zone, which is about 120 to 140 feet thick and composed of clay-rich oil shale. Below the R-1 zone is the L-0 zone. It ranges in thickness from 20 to 30 feet and has low-grade oil shale. The L-0 zone has a distinct influence on geophysical logs (density and resistivity). Early workers referred to this kick as the "Orange Marker". Below the L-0 zone is the lowermost continuous interval of oil shale in the Green River Formation, the R-0 zone. It is similar to the R-1 zone and is composed of clay-rich oil shale and one core drill, it was found to be about 127 feet thick. Below the R-0 zone additional thin beds of clay-rich oil shale are present, though they are interbedded with considerable quantities of sandstone, siltstone and lacustrine shale.

TABLE 2.1
GEOLOGIC SETTING

Formation or Stratigraphic Zone Name	Top (ft)*	Base (ft)*	TDS (mg/l)	Lithology
Uinta	0	1,237	300 - 1,000	sandstone and siltstone interstratified with horizons of silty marlstone, marlstone and lean oil shale
Green River – R-8	1,237	1,405		interbedded oil shale and occasional light to medium brown and light to medium gray siltstone
Green River - A Groove	1,405	1,421	500 - 2,000	tan to yellowish-tan lean oil shale and silty marlstone
Green River – Mahogany (R-7)	1,421	1,587		upper interval: laminated oil shale, dark gray to brown in color, lower interval: oil shale which is tan to grayish-brown to dark brown in color and usually laminated or structureless
Green River - B Groove	1,587	1,614	500 - 2,000	tan to grayish-brown to dark brown in color and usually laminated or structureless oil shale
Green River – R-6	1,614	1,782		lean to moderate-grade oil shale, vuggy oil shale, oil shale breccia (dissolution) and marlstone
Green River – L-5	1,782	1,966	>11,100	leached zone: vuggy and/or rubblized lean to moderate-grade oil shale or marlstone, saline zone: kerogen-rich nahcolitic oil shale and thick massive beds of stratiform nahcolite, halite or mixed nahcolite and halite.

The Dissolution Surface is estimated to be at 1904 feet within the L5 stratigraphic zone at the location of DVPW.

Green River – R-5	1,966	2,328		various nahcolite, halite and nahcolitic oil shale beds
Green River – L-4	2,328	2,489		small crystals and aggregate bodies of nahcolite and interbedded sequence of tan microcrystalline nahcolite and nahcolitic oil shale
Green River – R-4	2,489	2,642		rich oil shale, crystalline nahcolite aggregate bodies
Green River – L-3	2,642	2,672		minor amounts of nahcolite, high dawsonite content, oil shale has well developed laminated stratification
Green River – R-3	2,672	2,820		aggregate bodies and disseminated nahcolite crystals, low content of streaked, blebby and indistinctly laminated oil shale
Green River – L-2	2,820	2,849		laminated (banded) lean to moderate-grade dawsonitic oil shale, dark brown honeycomb nahcolite

Formation or Stratigraphic Zone Name	Top (ft)	Base (ft)	TDS (mg/l)	Lithology
Green River – R-2	2,849	2,948		nahcolite bearing part of zone is composed of laminated, streaked or blebby oil shale.
Green River - Garden Gulch (L-1, R-1, L-0, R-0)	2,948	3,264		tight, clay-rich oil shale
Green River – Cow Ridge to Wasatch "G" Sand (undifferentiated)	3,264	5,370		clay rich shale (with diminishing oil shale richness) and claystone

*estimated top and base of formations at DVPW well location

Proposed Injection Zone

An injection zone is a geological formation, group of formations, or part of a formation that receives fluids through a well. The proposed injection zones are listed in TABLE 2.2.

Injection will occur into an injection zone that is separated from underground sources of drinking water (USDWs) by confining zone(s) which is free of known open faults or fractures within the Area of Review.

The proposed injection zone is into the L-4, R-4, L-3, R-3, L-2, and upper portion of the R-2 stratigraphic zones in the Parachute Creek Member of the Green River formation at an estimated depth of 2,328 to 2,897 feet. The Dissolution Surface (approximately located at 1,904 feet) marks the extent of groundwater infiltration and top of the saline mineral deposits, or Saline Zone. The proposed injection zone is located below the Dissolution Surface, within the Saline Zone, where groundwater is not present, remains dry, and not considered USDWs. In general the injection zone is comprised of very tight, very low permeability nahcolitic oil shale.

TABLE 2.2
INJECTION ZONE

Formation or Stratigraphic Zone Name	Top (ft)*	Base (ft)*	TDS (mg/l)	Fracture Gradient (psi/ft)
Green River – L-4	2,328	2,489	NA	0.890
Green River – R-4	2,489	2,642	NA	0.890
Green River – L-3	2,642	2,672	NA	0.890
Green River – R-3	2,672	2,820	NA	0.890
Green River – L-2	2,820	2,849	NA	0.890
Green River – R-2 (upper)	2,849	2,897	NA	0.890

*estimated top and base of formations at DVPW well location

Unlike the existing Class III NSI project, which targets a 40 to 60 foot thick horizontal bed (Boies bed) in the L-5 stratigraphic zone, the proposed injection zone is a complex array of bedded and non-bedded nahcolite. The nahcolite occurs as finely disseminated crystals, nodules, crystalline aggregates, and several thin continuous beds. The dominant continuous beds are the Love, Greeno and TI, with a greatest thickness of approximately eight (8) feet. The nodules and individual crystals in the disseminated nahcolite make up approximately 25% to 30% of the rock volume and as the nodules and crystals dissolve leaving the structure intact, which reduces the risk of subsidence. Even in the thin continuous beds, up to 30% of the structure remains.

Confining Zones

A confining zone is a geological formation, part of a formation, or a group of formations that limits fluid movement above and below the injection zone. The confining zone or zones are listed in TABLE 2.3.

The United States Geological Survey (USGS) Produced Water Database was reviewed for regional water quality data below the injection zone. Based on the TDS values contained in the database, the Wasatch and Mesa Verde may be USDWs, near the NSI lease. A lower confining layer has also been identified below the injection zone.

Immediately above the injection zone resides the R-5, which has been identified as a confining zone, while the R-2 stratigraphic zone is the confining zone immediately below.

TABLE 2.3
CONFINING ZONES

Formation or Stratigraphic Zone Name	Top (ft)*	Base (ft)*	Formation Lithology
Green River – lower portion of L-5 and R-5	1,904	2,328	various nahcolite, halite and nahcolitic oil shale beds
Green River – R-2	2,897	2,948	nahcolite bearing part of zone is composed of laminated, streaked or blebby oil shale
Green River - Garden Gulch (L-1, R-1, L-0, R-0)	2,948	3,264	tight, clay-rich oil shale
Green River – Cow Ridge to Wasatch “G” Sand (undifferentiated)	3,264	5,370	clay rich shale (with diminishing oil shale richness) and claystone

*estimated top and base of formations at DVPW well location

Underground Sources of Drinking Water (USDWs)

Aquifers or the portions thereof which contain less than 10,000 mg/l total dissolved solids (TDS) and are being or could in the future be used as a source of drinking water are considered to be USDWs. The known USDWs within the lease area are the Uinta formation (including the discontinuous Perched Aquifer), and the A-Groove and B-Groove aquifers above and below the R-7 stratigraphic unit (Mahogany Zone), respectively and portions of the upper portions of the Dissolution Surface in the L-5 stratigraphic unit. The range of TDS values can be found in TABLE 2.4.

TABLE 2.4
UNDERGROUND SOURCES OF DRINKING WATER (USDWs)

Formation or Stratigraphic Zone Name	Top (ft)*	Base (ft)*	TDS (mg/l)	Notes
Uinta	0	1,237	300 – 1,000	
Green River - A Groove	1,405	1,421	500 - 2,000	
Green River - B Groove	1,587	1,614	500 - 2,000	
Green River - L5	1,782	1,966	2,500 – 50,000	Exempted Aquifer in portions of the lease

*estimated top and base of formations at DVPW well location

As noted in Table 2.4, the upper portion of the L-5 zone contains water of a quality and quantity that can be defined as a USDW. The aquifer exemption was made because the L-5 zone may experience some fracturing or collapse of overlying strata and aquifer, all within the L-5 zone, as a result of the solution mining of the Boies Bed. The Boies Bed or L-5A is located below the Dissolution Surface in the lower part of the L-5 zone.

During the 2003 reissuance of the CO30358-00000 permit, an aquifer exemption was provided for L-5 zone located at approximately 1,884 feet below ground surface (BGS) and the base of the R-6 zone at approximately 1,772 feet BGS within NSI BLM leases that are located in Township 1 South, Range 98 West, in Sections 15,16,17,21,22,23,25,26,27, and 28.

NSI has been monitoring groundwater quality in the sodium lease area for over a decade. In four wells that are monitoring the perched aquifer which resides in the Uinta formation, the average TDS varied from 453 to 649 mg/l. The four A-Groove aquifer monitoring wells average values are 722 to 5,090 mg/L TDS. The range on six B-Groove monitoring wells averages from 873 to 1,586 mg/l TDS. Finally, the seven Dissolution Surface monitoring wells range average from 12,700 to 65,151 mg/l TDS.

Based on the TDS values contained in the USGS Produced Water Database, the Wasatch and Mesa Verde may also be USDWs near the NSI lease, but site specific data is not available at this time.

PART III. Well Construction (40 CFR §146.22)

The approved well completion plan, incorporated into the Permit as APPENDIX A, will be binding on the Permittee. Modification of the approved plan is allowed under 40 CFR §144.52(a)(1) provided approval is obtained from the Director prior to actual modification.

All well materials must be compatible with fluids with which the materials come into contact and capable of withstanding the full temperature range planned for this project. The maximum temperature of the barren fluids injected through the wellbore will be 300 deg F. NSI, within the same lease boundary, and American Soda, on an adjacent lease, have existing Class III UIC permits to commercially mine nahcolite. The existing NSI mining project injects fluids that reach 250 deg F, while American Soda, presently all wells are shut-in, operated at higher temperatures, up to 400 deg F.

Casing and Cementing
The well construction plan was evaluated and determined to be in conformance with standard practices and guidelines that ensure well injection does not result in the movement of fluids into USDWs. Well construction details for this injection well are shown in TABLE 3.1.

TABLE 3.1
WELL CONSTRUCTION REQUIREMENTS

Casing Type	Hole Size (in)	Casing Size (in)	Cased Interval (ft)	Cemented Interval (ft)
Tubing	N/A	4.50	0 - vary	-
Intermediate	19.00	7.00	0 - 2,328	0 - 2,328
Surface	29.00	22.00	0 - 150	0 - 150

PART IV. Area of Review, Corrective Action Plan (40 CFR §144.55)

Area Of Review (AOR)
Under 40 CFR §146.6, the area permit AOR may be a fixed distance of not less than one quarter (1/4) mile or a circumscribing area in which the pressures in the injection zone may cause the migration of the injection and/or formation fluid into a USDW. The AOR for this area permit is defined to be a quarter mile outside of the NSI lease boundary.

A quarter mile is a conservative area to evaluate for the AOR. The proposed well will operate as a closed loop system whereby the fluids injected and recovered occur through the same well. At the relatively low maximum allowable pressure of 300 psig that the well will operate, it is unlikely for significant pressure build up to occur in the surrounding formation.

The Dudley Bluffs fault system, which is a major structural feature in the Piceance Creek Dome and in the vicinity of Piceance Creek and Ryan Gulch, crosses the southwestern corner of the Lease; however, it exhibits little or no displacement. Faults other than the Dudley Bluffs system have not been identified on the Lease or in immediately adjacent areas. Geophysical studies indicate that a fracture system may extend along strike onto and across the Lease towards Yellow Creek. According to NSI, although it is probable that fractures and minor faults associated with the Dudley Bluffs system may cross the southwestern corner of the Lease, it is not clear at the present time what significance they may have.

NSI has identified all wells within the area permit AOR. NSI states that there are no drinking water wells or residences within the lease boundary. NSI brings in bottled water for drinking water for their operations. There are two shallow domestic wells that are listed with the Colorado Division of Water Resources. According to NSI, these wells are believed to have been constructed in 1912 and are not used for domestic purposes. There have been no drinking water wells identified in the area permit AOR.

The location of all known wells within the area permit AOR which penetrate the confining zone, are required to be identified. The majority of the wells within the area permit AOR do not penetrate the confining zone, however at least 36 wells are deep enough to penetrate the confining zone. Due to the number of wells that will require well construction and plugging and abandonment review, a phased AOR well review process will be implemented for this permit. As individual injection wells are added to the area permit, the AOR wells which are within a quarter mile of the proposed well will be reviewed to ensure that the AOR well does not serve as a conduit for movement of fluids into USDWs. In the future, as NSI apply for additional wells, NSI will be required to provide EPA with an updated list of AOR wells within a quarter mile around the location of the proposed well to be added. And at that time, information such as CBLs, cementing records, plugging and abandonment plans, etc., will be provided to EPA for review.

NSI has submitted the area permit to initially include only one well which will be experimental in nature. The economic success of this well will determine the viability of further development of the deeper saline zone and additional wells associated with this permit. This phased AOR well review process will provide a more thorough assessment of the AOR wells, by ensuring inclusion of future drilled wells while avoiding unnecessary review and reducing the burden on the operator to provide the required AOR well information (CBLs, etc), should NSI decide not to pursue additional wells associated with this permit.

At this time, there are no AOR wells surrounding the proposed DVPW that penetrate the confining zone.

Corrective Action Plan (CAP)
For wells in the AOR which are improperly sealed, completed, or abandoned, the applicant will develop a CAP consisting of the steps or modifications that are necessary to prevent movement of fluid into USDWs.

At this time, there are no wells associated with the request for this area permit, within a quarter mile of the proposed injection well, DVPW, and no corrective action is needed. However, as additional new injection wells are added to the area permit, and the AOR wells are evaluated, a CAP may be required prior to authorization to inject for the additional well.

PART V. Well Operation Requirements (40 CFR §146.23)

Approved Injection Fluid
Approved injected fluids are limited to:

1. heated barren liquor to dissolve the nahcolite within the injection zone. The barren liquor may be fluids that have been produced from the operations associated with either this permit or the existing operation under the Class III Permit CO30358-00000
2. inert gas injected through the annulus of the tubing and intermediate casing

NSI has proposed injection of an inert gas such as nitrogen that will extend from surface (through the annulus of the tubing and intermediate casing) into the mining interval to control the top of the brine solution. The variable pressurized gas cap will be used to control the upward growth of mining interval and focus solution mining to specific horizons.

Injection of any hazardous waste as identified by EPA under 40 CFR §261.3 is expressly prohibited.

Injection Pressure Limitation
Injection pressure, measured at the wellhead, will not exceed the maximum calculated to assure that the pressure used during injection does not initiate new fractures or propagate existing fractures in the injection zones. In no case shall injection initiate fractures in the confining zone or cause the migration of injection or formation fluids into a USDW.

There is little data on the fracture gradient for the injection zone. A formation pressure test performed on an adjacent lease through the same intervals at 600 to 700 psig did not result in fracturing. The fracture gradient was calculated to be approximately 0.89 psi/ft.

The formation fracture pressure can be determined according to the following formula:

$$FP = [fg - (0.433 * sg)] * d$$

FP = formation fracture pressure (measured at surface)
fg = fracture gradient (from submitted data or tests)
sg = specific gravity (of injected fluid)
d = depth to top of injection zone (or top perforation)

NSI submitted injection fluid density data of the barren liquor (highest sg = 1.08). At a depth of 2,328 feet (top of the injection zone) and using the fracture gradient (0.89 psi/ft), the fracture pressure is estimated to be 983 psig. Because the barren liquor is injected while fluids are simultaneously recovered, NSI has requested a maximum allowable injection pressure of 300 psig. The maximum allowable injection pressure (MAIP) for the barren liquor is set at 300 psig. Since the MAIP is well below the estimated fracture pressure, NSI will not be required to perform a step rate test to verify the fracture gradient of the injection formation.

NSI is also authorized to inject an inert gas into the TCA. To be able to effectively displace the fluid and counterbalance the hydrostatic pressures exerted by the barren liquor at 300 psig, at the greatest depth, an annular pressure of 1700 psig is required. The Gas Cap MAIP is set at 1,700 psig.

Injection Volume Limitation
Cumulative injected fluid volume limits are set to assure that injected fluids remain within the boundary of the exempted area. Cumulative injected fluid volume is limited when injection occurs into an aquifer that has been exempted from protection as a USDW.

Presently, there are no aquifer exemptions associated with this permit and no fluid volume limits. Furthermore, in this process, as fluids are injected into the subsurface, the fluids are recirculated and brought back up to the surface within the same well.

Mechanical Integrity (40 CFR §146.8)
An injection well has mechanical integrity if:

1. there is no significant leak in the casing or tubing (Part I); and
2. there is no significant fluid movement into a USDW through vertical channels adjacent to the injection well bore (Part II).

The Permit prohibits injection into a well which lacks mechanical integrity. The Permit requires that the well demonstrate mechanical integrity prior to injection and periodically thereafter. A demonstration of mechanical integrity includes both internal (Part I) and external (Part II). The methods and frequency for demonstrating Part I and Part II mechanical integrity are dependent upon well-specific conditions as explained below.

Internal Mechanical Integrity (Part I MI) will be demonstrated prior to beginning injection. A successful Part I Mechanical Integrity Test (MIT) is required prior to receiving authorization to inject and repeated no less than five years after the last successful MIT. A demonstration of Part I MI is also required prior to resuming injection following any workover operation that affects the casing.

Part I MI is demonstrated by using the maximum permitted injection pressure or 1,000 psi, which ever is less, with a ten percent or less pressure loss over thirty minutes. The pressure test requires removing tubing and setting a temporary packer or retrievable bridge plug at the base of the intermediate casing. The pressure test will be required on both the production and injection casings.

External Mechanical Integrity (Part II MI) will be demonstrated by conducting a Temperature Survey. A baseline Temperature Survey will be conducted prior to authorization to inject. The first demonstration will be made between 60 to 90 days after injection have commenced. Subsequent demonstrations are required no less than five years after the last successful MIT. The temperature survey will be required on both production and injection strings.

PART VI. Monitoring, Recordkeeping and Reporting Requirements

The goals of the proposed monitoring programs are to ensure that the well integrity is not compromised as a result of mining activities, temperatures and pressures will be closely monitored to ensure certain established limits are not exceeded, and to monitor the water quality in the USDWs. The monitoring program is described below and the requirements are summarized in APPENDIX D of the Permit.

Once an alarm sounds or upon discovery that there is an exceedance in the permit condition, the response and shutdown process will be followed.

Response and Shutdown Process

The response and shutdown process entails investigating the origin to determine that the permit exceedance and/or alarm sounded as a result of a valid concern and not a false alarm before proceeding to the shutdown process. The shutdown process entails immediately ceasing injection, to determine cause and remediate the problem. All events that trigger the shutdown process will be reported to the EPA within 24 hours. All events that sound an alarm due to a permit condition exceedance will be documented and reported in the quarterly report.

Injection Well Monitoring Program

Continuous monitoring will be carried out with instrumentation that will be capable of recording at least one value for each of the parameters (injection and production pressures, annulus pressure, injection and production flowrates, and injectate and production temperatures) at least every thirty (30) seconds. Recordings should be made at least once every ten (10) minutes.

Monthly averaged, maximum, and minimum values for injection pressure, injection and production flow rates, and injectate and produced fluid temperatures are required to be reported as part of the Quarterly Report to the Director.

TUBING CASING ANNULUS MONITORING

The tubing casing annulus will be continuously monitored to monitor the pressure of the gas blanket. If the gas blanket is not used, it will aid in the detection of leaks should the casing fail.

INJECTATE AND PRODUCTION FLUID SAMPLING

The Permittee will be required to provide access for sampling the injected fluid, a tap, isolated by shut-off valves. All sampling and measurement taken for monitoring must be representative of the monitored activity.

A daily bicarbonate assay will be performed on the injected barren liquor as well as the produced fluid to provide chemistry information including specific gravity. The information will also be used to better understand mining interval growth. The Permittee must also analyze, quarterly, a sample of the injectate for the pH, TDS and specific conductivity. This analysis will be reported to EPA as part of the Quarterly Report to the Director.

WELLHEAD MONITORING

The Permittee will be required to install and maintain wellhead equipment. Required wellhead equipment includes but is not limited to: 1) continuous recording devices for injection pressure, produced fluid and injectate temperatures, production and injection flow rates, and annular pressure, 2) shut-off valves located at the wellhead on the injection; 3) flow meters that measures the cumulative volumes of injected and produced fluids; 4) fittings or pressure gauges attached to the injection and production tubing and the annulus between the intermediate casing and tubing.

TEMPERATURE

The injectate and produced fluid temperatures will be continuously monitored to ensure that the operating temperature does not exceed the permit limit of 300 deg F and does not adversely affect the formations containing USDWs.

A number of kerogen pyrolysis experimental studies have been performed to determine the kinetic rates as a function of temperature. By weight, Green River Shale is approximately 10% shale oil. At temperatures below 500 deg F, only 10% of the shale oil is extractable, or 1% by weight of the formation. In general, the kinetic relationship between the temperature and the time is governed by Arrhenius' law, where, at higher temperatures, a shorter amount of time is required for the shale oil to be produced. At lower temperatures, the amount of time exponentially increases. Using the reaction constants from the Burnham, et, al, 1987[1] paper, at 300 deg F, it would take over 2,000 years before the kerogen in the shale oil is generated. Therefore, at a maximum temperature of 300 deg F, oil is not expected to be generated during the project life.

MINING INTERVAL MONITORING

NSI proposes to in-situ solution mine, primarily disseminated, non-stratiform, nahcolite from the Saline Zone. The mined interval is anticipated to be approximately 500 feet in height and have a maximum diameter of 250 feet. Within the Saline Zone, the disseminated nahcolite is estimated to be approximately 25% of the formational volume. Anticipated recovery of the disseminated nahcolite within the mined interval is estimated to be approximately 70% of the total disseminated formational nahcolite, leaving 82.5% of the formational material in place. The remaining oil shale and nahcolite structure that remains in place will provide formational support, reducing the risk of subsidence. Additionally, the pore space fluids will, in effect, provide additional support in the form of a "pore pressure". The thin bedded intervals, Love, Greeno, and TI beds, will be more uniformly mined, however, the depths of these beds vary from 6 to 8 feet. Even in these thin continuous beds, up to 30% of the structure remains.

Mining interval development shall be monitored to estimate extent the nahcolite has been produced. Because the leached solution mining interval will be a matrix of oil shale rather than a void, size and shape must be determined by indirect methods. Material balances of the volumetric fluid flow rates into and out of the solution mining interval shall be performed. Continuous monitoring of flow rates and densities will provide an ongoing material balance, which will allow the Permittee to make calculations of the mass of nahcolite extracted, this information will be submitted with the quarterly report.

SUBSIDENCE MONITORING

The subsidence monitoring plan includes both surface and subsurface monitoring to detect surface and subsurface movement as a result of NSI's mining activities.

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[1] "*Comparison of Methods for Measuring Kerogen Pyrolysis Rates and Fitting Kinetic Parameters*" by Burnham et al. UCRL-95660 193rd Meeting of the American Chemical Society, Denver, Colo. (Apr. 5, 1987)

Subsurface Subsidence
Two methods for detecting subsidence at depth are time domain reflectometry (TDR) and geophysical logging. The TDR is preferred since the monitoring is a continuous process, whereas the geophysical logging occurs periodically.

Time Domain Reflectometry (TDR)
Initially, the area permit will consist of only the DVPW. The potential for subsidence will increase when additional wells are installed into the same interval. For the first well installed, TDR will not be required. However, when an additional well is added to the permit and there are two or more wells operating simultaneously, the additional well will include TDR, or equivalent technology, for determination of subsurface movement of strata overlying the mining interval. After which, any additional wells added to the permit will require TDR monitoring. TDR is an electrical pulse-testing technique, whereby a pulse is created in the coaxial cable and returns a reflected signal when the cable experiences a crimp or elongation. The TDR will be attached to the outside of one of two intermediate casings and cemented in place. Materials will be used that can withstand the maximum anticipated temperature. The minimum depth of the TDR is to the base of the L-5 zone.

NSI has previously experienced difficulties with this technology due to installation and operational (water intrusion) difficulties. The problems that NSI has experienced may be more of an installation issue and when properly installed, the TDR is capable of continuously monitoring subsidence activities near the wellbore. There are currently two operable TDR monitoring wells in the NSI subsidence monitoring program. NSI understands that ongoing technological advances may offer additional methodologies. Other subsurface monitoring techniques may be employed, provided the operator submit sufficient information to demonstrate that the alternative will provide equivalent subsidence monitoring to that of the existing monitoring technique, and the alternative monitoring technique is approved by the Director. If approved, the Permit will be changed to include the new alternative by issuance of a Minor Modification.

Geophysical Monitoring
A baseline gamma log will be required for all wells, as part of the logging regime to be completed at the time of well drilling and will be used as a baseline log to compare with additional gamma log runs during the operational phase. TDR is not required for the DVPW and subsurface subsidence monitoring will require a gamma log run on the DVPW well after achieving production intervals of 100,000 tons. If the anticipated mining interval is successfully mined, it will result in approximately 308,131 tons of produced nahcolite, or four logs over the expected life of the well, including the baseline. When the TDR is installed, the periodic logs will not be required during the operational phase, however, in the event that the TDR does fail, a gamma log will be required within 3 months after discovery of the TDR failure and 100,000 ton intervals thereafter.

Past experience on an adjacent BLM lease have shown that the well bores are subject to mineral and metals buildup during the solution mining process. This scaling affects the ability to run and interpret gamma logs, effectively masking the radioactive signature of the formations. The degree of interference from scaling is somewhat variable and may not be reliable as a means to identify or evaluate subsurface subsidence.

Surface Subsidence
The *Comprehensive Monitoring Plan* required by BLM, is based on a phased approach and has recently been updated in July 2010. This plan includes the Surface Subsidence Plan and will be incorporated into this UIC area permit, by reference. This document may be revised and updated in the future.

Throughout the existing mining site, operating under the existing UIC Class III Permit CO30358-00000, there are a number of surface subsidence monuments that have been put into place, used to detect movement at the surface above the mined cavity. These monuments are checked once every two years and will help alert of potential surface subsidence issues. NSI has detected no surface subsidence after 18 years of surface subsidence monitoring. Due to the proximity of the mining locations of the existing wells in Permit CO30358-00000, it may be difficult to identify if the cause is due to the existing wells in Permit CO30358-00000 or wells associated with this newly proposed permit.

Groundwater Monitoring Program
Also included in the *Comprehensive Monitoring Plan*, dated July 2010 and required by BLM, is Section 2.0 Ground Water Monitoring Plan, which will be incorporated into the UIC area permit by reference. The sampling protocol and analytes tested will follow the *Groundwater Sampling and Analysis Plan for Natural Soda* dated January 2011. Both these documents may be revised and updated in the future.

NSI has a network of monitoring wells in place associated with their existing UIC Class III Permit CO30358-00000, to monitor groundwater quality and piezometric pressures that are up-gradient, down-gradient, as well as within the existing well field. These groundwater quality monitoring wells collect samples from the Dissolution Surface, B-Groove, A-Groove, and Perched Aquifers. NSI has been conducting groundwater monitoring since 1990 and to date only one anomaly, has been detected early on in the operational history. Prior to 1995, the solution mining cavities were operated under pressure. With the close proximity of the mining at the time to the plant's water supply well (90-1), mining fluid infiltration was detected at 90-1. The issue was remediated by installing downhole pumps and continuing to pump 90-1 and utilizing the water in the NSI solution mining operations. No water quality anomalies were noted up-dip or down dip from this well. The 90-1 well has since recovered to its historical, baseline water quality levels. The solution mining technology currently employed is focused on operating the cavities in equilibrium with the dissolution surface to eliminate the driving force for mining fluids to migrate to the overlying aquifers.

NSI is also aware that Williams Energy Services is directionally drilling and will operate natural gas production wells in the vicinity of the NSI lease boundary. The groundwater monitoring plan will be modified accordingly to ensure the mining activities are not adversely impacted.

Both the surface subsidence and groundwater monitoring programs are applicable for UIC Permit CO30358-00000 and this permit CO32169-00000. NSI may submit one copy of these quarterly reports to fulfill the reporting requirements for both permits.

PART VII. Additional Wells to Area Permit

Additional new injection and production wells may be added to the area permit as necessary pursuant to 40 CFR §144.33, provided the Permittee provides notice to the Director. The Director periodically will review the cumulative effects pursuant to 40 CFR §144.33 and advise the Permittee of any required changes to the Permit or mine operations. All sections of the area permit apply to additional well(s) approved for injection. Additional requirements beyond those described in this permit may be required for additional wells that will be included in this area permit.

Any changes to the construction or plugging and abandonment plans must first be approved by the Director and the Permittee shall not begin construction or conversion of the well(s) of the plan until after receiving written authorization from the Director. For each new well added, the AOR must be revaluated for wells which penetrate the confining zone. A corrective action plan may be required if the wells are determined to be improperly sealed, completed, or abandoned.

Additional wells that are added to the area permit must be constructed a minimum distance of 350 feet, from center of any existing well bore under this permit to center of the newly proposed additional well. At no time, should the mined subsurface area of the CO30358-00000 permit overlap the mined surface area of wells associated with this permit. In the future, after additional information has been gained regarding subsidence potential at this site, NSI may request a modification of this permit requirement if NSI is able to demonstrate (through modeling or other scientifically based information) that there will not be an increase risk of subsurface subsidence.

PART VIII. Plugging and Abandonment Requirements (40 CFR §146.10)

Plugging and Abandonment Plan
Prior to abandonment, the inert gas used to create the gas cap will be collected at the surface and properly disposed (if applicable). The injection and production tubings will be pulled from the wellbore. A Cement Bond Log or Cement Evaluation Log will be required for both intermediate casings to verify integrity of cement behind the casing has not been compromised. Prior to injection, a Gamma Ray Log was run through one of the two casings, a Gamma Ray Log will be required on the same casing, and results of the two logs will be compared to determine if any changes occurred in the positions of the casing location collars, indicating possible subsurface movement. The wells will be plugged from total depth to surface and any casing leaks will be taken care of when the well is plugged.

NSI intends to leave brine from the mining operation in the mining interval. The residual brine would fill the pore spaces that had previously been occupied by the mined nahcolite crystals to provide support and stabilize the mined interval.

The well will be plugged in a manner that isolates the injection zone and prevents movement of fluid into or between USDWs, and in accordance with any applicable Federal, State or local law or regulation. A cast iron bridge plug (CIBP) will be set near the base of both casings, at approximately 2,328 feet. Tremie cement will be placed from the bridge plugs to surface with top off cement, added as necessary.

Within sixty (60) days after plugging the owner or operator will submit Plugging Record (EPA Form 7520 13) to the Director. The Plugging Record must be certified as accurate and complete by the person responsible for the plugging operation. The plugging and abandonment plan is described in APPENDIX E of the Permit.

PART IX. Financial Responsibility (40 CFR §144.52)

Demonstration of Financial Responsibility
The Permittee is required to maintain financial responsibility and resources to close, plug, and abandon the underground injection operation in a manner prescribed by the Director. The Permittee will show evidence of such financial responsibility to the Director by the submission of a surety bond, or other adequate assurance such as financial statements or other materials acceptable to the Director. The Regional Administrator may, on a periodic basis, require the holder of a lifetime permit to submit a revised estimate of the resources needed to plug and abandon the well to reflect inflation of such costs, and a revised demonstration of financial responsibility if necessary. Initially, the operator has chosen to demonstrate financial responsibility with:

Letter of Credit

Evidence of continuing financial responsibility is required to be submitted to the Director annually.